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Published in:
Nanomaterials

DOI:
[10.3390/nano10091818](https://doi.org/10.3390/nano10091818)

Publication date:
2020

Citation for published version (APA):

Davarpanah, A. (2020). Parametric study of polymer-nanoparticles-assisted injectivity performance for axisymmetric two-phase flow in EOR processes. *Nanomaterials*, 10(9), [1818].
<https://doi.org/10.3390/nano10091818>

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Article

Parametric Study of Polymer-Nanoparticles-Assisted Injectivity Performance for Axisymmetric Two-Phase Flow in EOR Processes

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Received: 10 August 2020; Accepted: 10 September 2020; Published: 12 September 2020



Abstract: Among a wide range of enhanced oil-recovery techniques, polymer flooding has been selected by petroleum industries due to the simplicity and lower cost of operational performances. The reason for this selection is due to the mobility-reduction of the water phase, facilitating the forward-movement of oil. The objective of this comprehensive study is to develop a mathematical model for simultaneous injection of polymer-assisted nanoparticles migration to calculate an oil-recovery factor. Then, a sensitivity analysis is provided to consider the significant influence of formation rheological characteristics as type curves. To achieve this, we concentrated on the driving mathematical equations for the recovery factor and compare each parameter significantly to nurture the differences explicitly. Consequently, due to the results of this extensive study, it is evident that a higher value of mobility ratio, higher polymer concentration and higher formation-damage coefficient leads to a higher recovery factor. The reason for this is that the external filter cake is being made in this period and the subsequent injection of polymer solution administered a higher sweep efficiency and higher recovery factor.

Keywords: polymer flooding; formation rheological characteristics; polymer concentration; recovery factor; mathematical model; nanoparticles

1. Introduction

Enhanced oil-recovery (henceforth; EOR) techniques are known as efficient methods in oil production from hydrocarbon reservoirs when natural drive mechanisms could not provide sustainable and economic production [1–3]. EOR techniques contain two main categories of thermal and chemical recovery methods. Among a wide range of chemical EOR techniques, polymer flooding has been considered to be an efficient recovery technique, especially for heavy oil reservoirs. In this technique, polymer molecules are added to water for the purpose of mobility reduction to increase water viscosity than oil in place [4–8]. Therefore, oil could mobilize easier than water, which caused to enhance oil production rate. In addition, the increase of viscosity would cause a viscous pressure gradient through the productive layers with a wide range of permeabilities. Thereby, polymer solution from the high-permeability layers has conducted to the low-permeability layers partially to increase oil mobility ratio [9–13]. The pervasive force of polymer injectivity techniques is utterly depended to the appropriate propagation of the polymer near the wellbore areas to remain the preferable mobility within the pore volume injection processes [14,15]. Degradation and retention for polymer injectivity are considered as the principal factors which severely impact the transportation of polymer in the porous medium [16–18].

The common types of polymers that are used in the polymer flooding procedures divided into biopolymers and synthetic polymers. Synthetic polymers such as polyacrylamide (PAM), hydrolyzed polyacrylamide (HPAM), xanthan, biologic polysaccharide and some of the natural polymers like

hydroxyl ethyl cellulose (HEC), sodium carboxyl-methyl cellulose and guar gum that are modified in specific processes are the most ubiquitous polymers in petroleum industries. The advantages of these polymers are as follows:

PAM (polyacrylamide): Due to its high value of molecular weight (approximately more than 10^6 gr./mole) that usually performed as a thickening agent for the aqueous solutions. Moreover, PAM has its stable properties at the temperature of 90 °C at the normal salinity and at the salinity of seawater; the temperature is set up at 62 °C Hence, it is worthwhile that this type of polymer would be restricted on the on-shore performances [19].

HPAM (hydrolyzed polyacrylamide): It is considered as one of the popular polymer types in the operational circumstances. It is constructed by the hydrolysis procedure of PAM or by the copolymerization of acrylamide and sodium acrylate. HPAM has some advantages rather other polymer types that would be considered as the preferable type for its administration in the polymer flooding performances. These advantages are entailed low costs, the ability of this polymer to tolerate in the presence of high value of mechanical forces and its high potential to resist against bacterial attack. In addition, this type of polymer could be utilized up to the temperature of 99 °C that is utterly depended to the hardness of reservoir brines. On the contrary, the disadvantage of HPAM is the high sensitivity to the salinity of brines, surfactant present and hardness of brine [20].

Xanthan gum: Xanthan has very high amount of molecular weight of $2\text{--}50 \times 10^3$ Kg/mole with the sever chains of polymer which made them approximately insensitive to the hardness and high value of salinity. One of the advantages of this polymer is to be compatible with different types of fluid additives and most of the surfactants. On the other hand it is very sensitive to degradation by bacterial activity when it was injected to the reservoir at low temperature regions [21].

Thereby, to select the best type of polymers that has the most appropriate compatibility with the properties of reservoir rock and fluid, numerous parameters should be taken into consideration. First, it is required to consider the oil viscosity and the permeability of the reservoir to obtain the best molecular weight for polymer solution. Second, it is essential to determine the cloud point of polymer that is clearly related to the thermal stability of polymer in the high temperatures and high salinity of brines. Another essential parameter is the polymer retention, which encompasses possible mechanisms responsible for the reduction of mean velocity of polymer molecules during their flow through porous media. A schematic of polymer flooding performances is schematically depicted in Figure 1. As shown in Figure 1, polymers were injected near the wellbore areas which is operated as four main categories after injection. The first polymer molecules has adsorbed on the rock surfaces and when these molecules merge together between rock surfaces, entangled polymer chains has deformed. These entangled chains would be performed as obstacles through the pore-throats and restricted the fluid flow. Undissolved polymer fractions which is known as the polymer junks can plug the near wellbore spaces. It is shown as green color on the wellbore entrance.

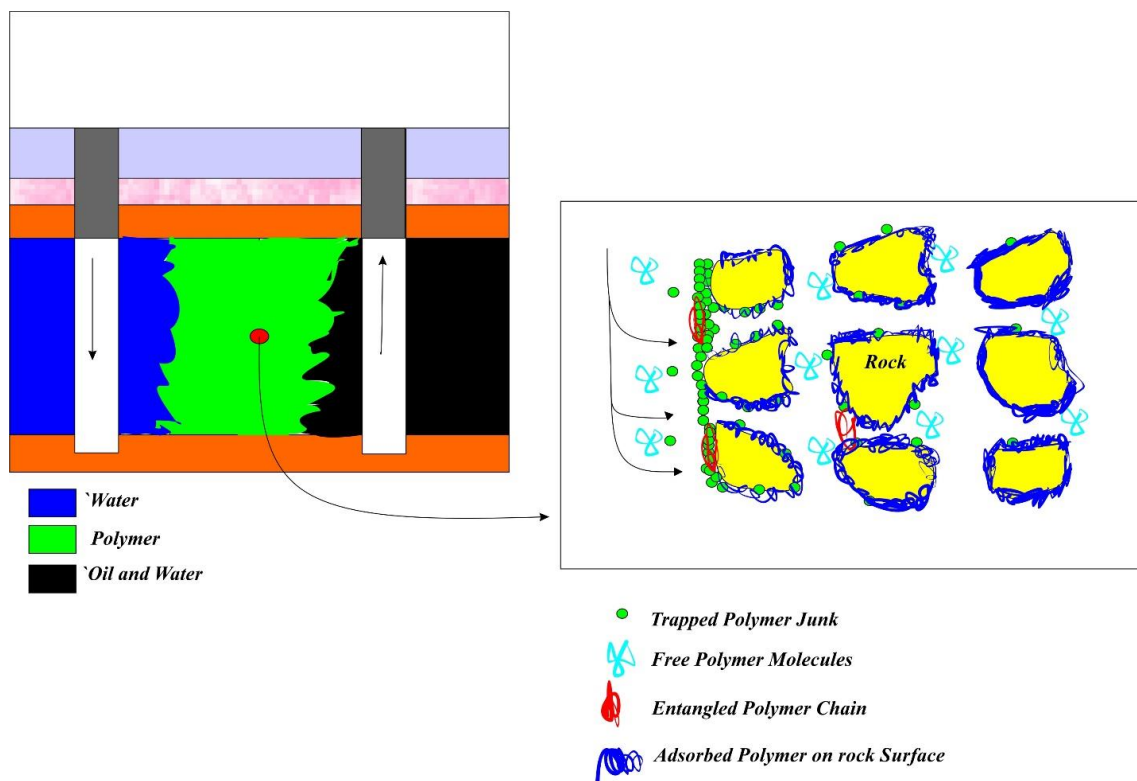


Figure 1. Schematic of polymer flooding performances.

Nanoparticles (found as colloidal suspensions as part of natural reservoirs) are an indispensable part of reservoir materials, are considered as in situ particles in porous media and are released with flowing flow. The primary function of these nanoparticles is to be easily transferred in the fractures. Thereby, they can fill tight, small cracks and pores and induce fundamental changes in permeability reduction due to their strong impact on pore plugs. Furthermore, there are a wide variety of factors that exert a considerable influence on controlling nanoparticles migration, such as increasing flow velocity and rise of pressure drop during the low-salinity water-flooding procedures [19]. In this paper, a mathematical model of polymer-nanoparticles-assisted injectivity performance was developed to control the mobility of nanoparticles migration. As a result, permeability can be improved dramatically in water-swept zones. Permeability reduction due to nanoparticles migration occurs via three different mechanisms: (1) pore-throat plugging, which takes place when the nanoparticle sizes are more than pore-throat size and the fluid flow is permanently reduced; (2) gradual reduction in pore size due to slight sedimentation of nanoparticles, in which pores are filled with smaller nanoparticles, thus reducing the permeability; (3) accumulation of various-sizes of nanoparticles on the pore-throat forming a bridge and consequently reducing the transfer of fluid [22,23]. Hence, geological characterization of formations such as the heterogeneity of formations has a profound impact on permeability reduction in terms of the plugging of formation structures by the injected fluid.

To define well injectivity, we use as the following equation for the injectivity index (II). This index is the well rate per pressure drop unit between the reservoir and the well, in which the impedance is defined as the normalized reciprocal well index:

$$J(t) = \frac{II(t=0)}{II(t)} = \frac{q(t=0)}{\Delta p(t=0)} \frac{\Delta p(t)}{q(t)}, \quad \Delta P = p_w - p_{res} \quad (1)$$

where p is the pressure and q is the well flow rate. J is the dimensionless pressure drop when the rate of the well is constant [24].

Although many studies and laboratory investigations in the literature espouse the importance of polymer flooding techniques on oil-recovery enhancement, we have tried to derive a mathematical equation for simultaneously calculating the recovery factor through the axisymmetric two-phase polymer-nanoparticle-assisted extraction. Inasmuch, polymer impedance is modeled for heavy oil reservoirs. Moreover, the rheological properties of the formation and the polymer concentration on the recovery factor were parametrically analyzed to compare the considerable influence of each reservoir characteristics. Therefore, the structure of this paper is divided in three sections: (1) governing equations for the displacement of oil by the polymer solution, (2) calculating the pressure drop value by considering and comparing rheological properties and last, (3) investigating the profound impact of each parameter on the recovery factor.

2. Governing Equations for Oil Displacement by Polymer Solution

The injectivity of a polymer solution greatly affects sweep efficiency and subsequent oil recovery. Thus, it can greatly affect project costs and has a significant effect on decision-making. In this section, governing equations for flow of polymer solution containing nanoparticles (colloidal or fines suspension, as mentioned in the introduction section) in porous media are reviewed. The effect of damage-free solutions, solutions without nanoparticles and solutions with polymer and slug-particle damage in heavy oil reservoir are discussed.

2.1. Damage-Free Oil Displacement by Water

The explicit formula derived by Kalantariasl et al. (2014), for displacement of oil by water is used for describing well-injectivity behavior during water injection into oil reservoirs with different viscosity. They assumed incompressible and immiscible flow of oil and water and used mass conservation of oil and water, generalized Darcy's law for water and oil. Then, equations for one dimensional axisymmetric flow were solved. Finally, impedance due to damage free water injection were derived as follows [25]:

$$J_{BL}(t_D) = \frac{k_{rowi}}{(-\ln x_w)} \int_{x_w}^1 \frac{1}{x_D \Lambda(S(x_D, t_D))} dx_D \quad (2)$$

where J_{BL} is the damage-free impedance, k_{rowi} is oil phase relative permeability at initial water saturation, x_w is dimensionless squared well radius $\left(\frac{r_w}{r_e}\right)^2$, x_D is the dimensionless squared radius $\left(\frac{r}{r_e}\right)^2$, Λ is the dimensionless total mobility, s is saturation that depended dimensionless position (x_D) and time (t_D), and t_D is the dimensionless time (PVI).

High-viscosity oil causes rapid water injection and increases in well injectivity (decrease of well impedance or pressure due to displacement of heavy oil by low viscous water). Injectivity depends on the water permeability end-point relative to oil at initial water saturation, well and reservoir dimensions and saturation-dependent mobility of oil and water.

2.2. Oil Displacement by Water Containing Dispersed Nanoparticles

Normally, injected water contains dispersed nanoparticles (fines or colloidal suspension) that may be retained in the porous media with flowing water and decrease permeability. Once massive pore blockage occurs and permeability declines, solid particles can no longer penetrate into the formation due to narrowed pores and a buildup of external porous media on the injection wall (external filter cake).

Kalantariasl et al. (2014) derived equations for the simultaneous effect of damage-free impedance changes due to variation in mobility (Equation (2)) and nanoparticle retention near the wellbore, i.e., deep filtration of particles and external cake formation on the injection face as follows:

$$J(t_D) = \begin{cases} 1 + mt_D & t_D < t_{Dtr} \\ 1 + mt_{Dtr} + m_c(t_D - t_{Dtr}) & t_D \geq t_{Dtr} \end{cases} \quad (3)$$

Addition of Equation (2) to Equation (3) gives the final expression for the impedance as Equation (4):

$$J(t_D) = \begin{cases} J_{BL}(t_D) + \frac{m}{M}t_D, & t_D < t_{rr} \\ J_{BL}(t_D) + \frac{m}{M}t_{rr} + \frac{m_c}{M}(t_D - t_{rr}), & t_{rr} < t_D < t_e \\ J_{BL}(t_D) + \frac{m}{M}t_{rr} + \frac{m_c}{M}(t_e - t_{rr}), & t_D > t_e \end{cases} \quad (4)$$

where $J(t_D)$ is the total impedance (due to both mobility ratio effect and formation damage), m is the slope of impedance growth during deep-bed filtration stage of suspended particles, m_c is the slope of impedance growth during cake formation stage, and M is the mobility ratio.

Oil displacement by polymer solutions containing dispersed particles from polymers added into the system must be considered, since polymers highly affect injectivity. Injectivity behavior due to displacement of oil by polymer solutions containing dispersed nanoparticles has three separate parts: changes in injectivity due to damage-free oil–water mobility variation, changes in injectivity due to damage resulting from retention of dispersed particles and changes in injectivity due to addition of polymer into the system.

Therefore, the explicit formula is derived for the simultaneous injection of polymer and nanoparticles as the following equation:

$$J_{polymer}(t_D) = J_{BL}(t_D) + J(t_D) + \frac{(q/\Delta p)_{t=0}}{(q/\Delta p)_t} \quad (5)$$

where Δp is the pressure drop after polymer flooding. Its further details are discussed in Appendix A, $J_{BL}(t_D)$ and $J(t_D)$ is calculated from equations 2 and 3, q is assumed in the flooding scenario, $\Delta p_{t=0} = (P_e - P_{wf})$ at the initial time which was calculated by $-Ln x_w / K_{rowi}$, Δp_t is Polymer flooding pressure drop which is explained explicitly in appendix A. Therefore, the total impedance for polymer flooding is defined as Equation (6):

$$J_{polymer}(t_D) = J_{BL}(t_D) + J(t_D) + \left(\frac{\Delta P_t}{\frac{-Ln x_w}{K_{rowi}}} \right) \quad (6)$$

The following assumptions are taken into consideration to espouse the importance of driving mathematical equations for calculating pressure drop: there is incompressibility and flow direction in one dimension for the aqueous polymer solution in the porous media by the consideration of mechanical entrapment and polymer adsorption; the concentration of the polymer is not large enough to severely emphasize the volumetric balance of solution in the aqueous phase, i.e., the profound impact of polymer on the solvent density is being ignored and the proportionality coefficient is considered as the filtration coefficient, which is in good agreement with the experimental data. In addition, it has been elaborated that polymer solution viscosity has a rising pattern regarding the polymer concentration increase, i.e., (see Farajzadeh 2016 and Bedrikovetski 2008 for further detailed discussion about these assumptions). The rheological properties of formation play a significant role in the pressure drop of the reservoir, and subsequently affect the recovery factor. These rheological specifications are the mobility ratio (M), formation-damage coefficient (βf), resistance—or permeability-reduction factor (R), porosity (Φ), filtration coefficient (λ), concentration of the polymer solution, maximum dimensionless adsorbed-polymer concentration (C_{max} —obtained from the Langmuir adsorption isotherm—and nonlinearity of the isotherm (b). These principal factors and how such parameters would emphasize the polymer injectivity procedures are detailed below.

2.2.1. Mobility Ratio

In this part of the study, we focus on the calculation of pressure drop with the following assumptions that are taken into the consideration. The mobility ratios changes were assumed to be 1, 2, 5, 20, 50, 85, 100 and its dominant influence on the polymer injectivity pressure drop were modeled.

As seen in Figure 2, the increase of mobility ratio through the formations has specifically influence the pressure drop and it shows a dramatic rise in the increase of mobility ratio.

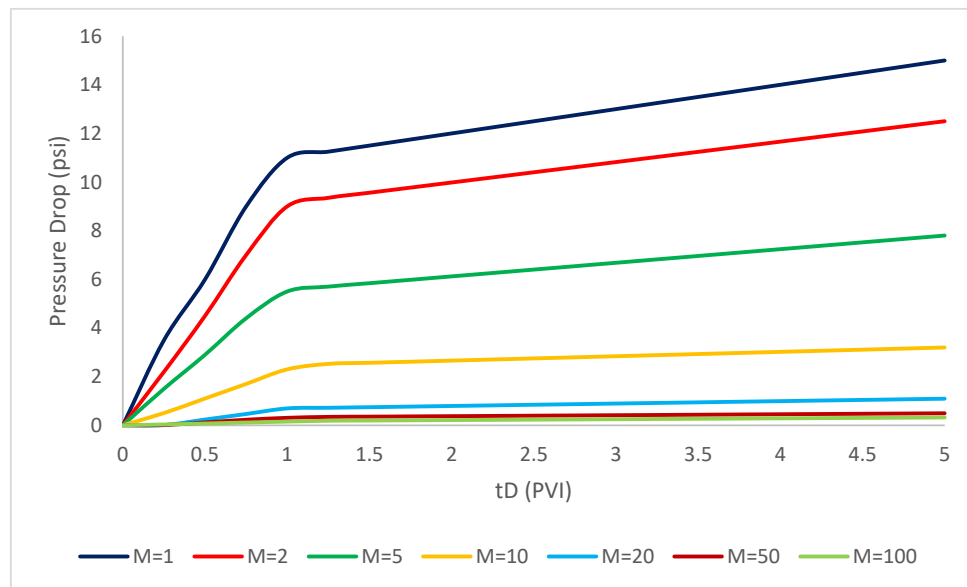


Figure 2. Effect of mobility ratio differentiations on the pressure drop during polymer injection ($r_w = 0.25$ ft; $r_e = 0.1200$ ft; $\Lambda = 1$ 1/ft; $C_{max} = 2.2 \times 10^{-6}$ ppm; $b = 10$; $B_f = 4000$; $R = 1500$; $C_p = 0.002$ ppm; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$).

2.2.2. Polymer Concentration

In this part of the study, we focus on the calculation of pressure drop with the following assumptions which are taken into the consideration, and the polymer concentrations are assumed 200×10^{-6} , 1000×10^{-6} , 2000×10^{-6} , 3000×10^{-6} , 4000×10^{-6} , 5000×10^{-6} . As shown in Figure 3, the increase of polymer concentration through the polymer injectivity procedure has considerably influence the pressure drop and it experienced a gradual rise regarding the increase of polymer concentration.

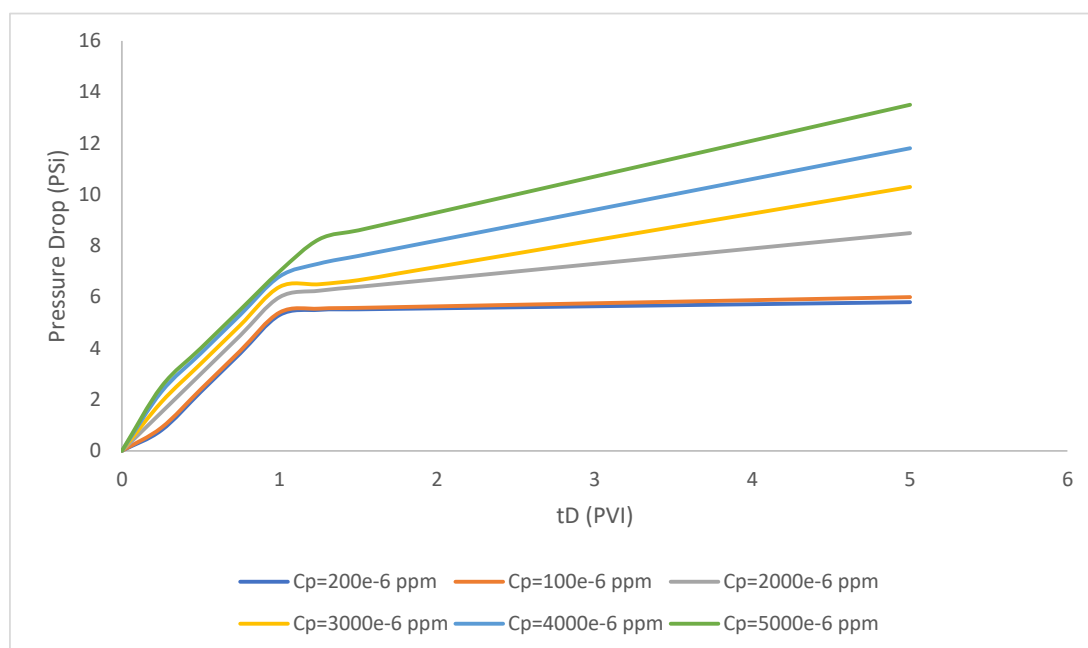


Figure 3. Effect of polymer concentration differentiations on the polymer injectivity pressure drop.

2.2.3. Filtration Coefficient

In this part of the study, we focus on the calculation of pressure drop when the filtration coefficients are assumed 200, 1000, 2000, 3000, 4000. As shown in Figure 4, the increase of filtration coefficient through the polymer injectivity procedure has a considerable influence on the pressure drop and it experiences a gradual rise with an increase of filtration coefficient.

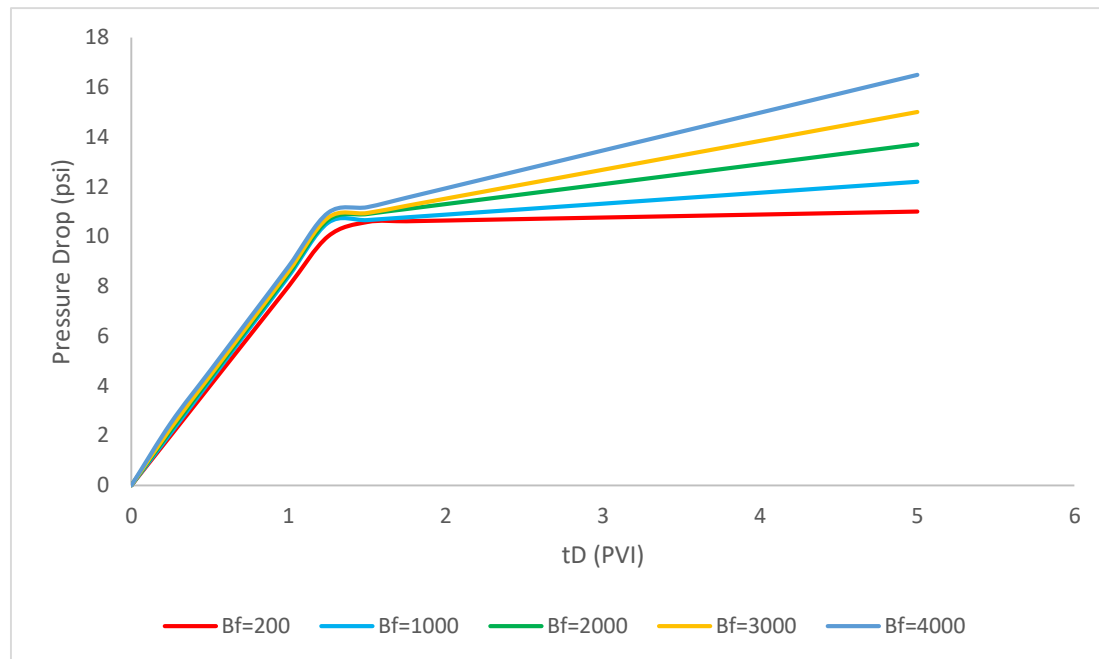


Figure 4. Effect of filtration coefficient differentiations on the polymer injectivity pressure drop ($r_w = 0.25$ ft; $r_e = 0.1200$ ft; $M = 2$; $\Lambda = 1$ 1/ft; $C_{max} = 2.2 \times 10^{-6}$ ppm; $b = 10$; $R = 1500$; $C_p = 0.002$ ppm; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^0 = 5 \times 10^{-6}$).

Regarding the calculated pressure drop by the obtaining formula, it is excluded that the resistance or the permeability-reduction factor, porosity and the maximum dimensionless adsorbed-polymer concentration is not administered a considerable influence on the pressure drop. Therefore, we can neglect the effect of these parameters in the pressure drop calculation.

3. Results and Discussion

To compare the profound impact of the rheological parameters and concentration of polymer solution on the calculation of polymer-injectivity recovery, three different scenarios were taken into the consideration to emphasize the importance of each parameter explicitly.

3.1. Mobility Ratio (M)

In this scenario, by the following assumptions, the recovery factor for axisymmetric two-phase polymer flow with simultaneous deep-bed filtration of injected nanoparticles are calculated mathematically. As shown in Figure 5, effect of different mobility ratios 1, 2, 5 and 10 on the polymer impedance were analyzed. In other words, all the particles and polymer properties is considered as the constant values and the variable parameter is mobility ratio. As evident in Figure 5, the recovery factor for the injection of polymer solution coupled with the simultaneous nanoparticle injection was modeled. The recovery factor has risen drastically in the first period of injection due to the significant influence of polymers in the settlement of water. Hence, water viscosity enhancement lead to more oil mobilization and subsequently the recovery factor has increased dramatically in the pore volume injection. The reason for this sharp rise is due to the formation of filter cake in this time period. After

this, it has increased slightly in the next pore-volume injectivity and this is related to the deposition of polymer junks in the pores. It utterly depended to the constant maximum thickness of external cake after the equilibrium time. Furthermore, the polymer injectivity pattern for all the mobility ratios have witnessed a similar increase trend. The higher mobility ratios has the higher recovery factor due to the more oil mobilization through the formation. Consequently, as shown in Figure 5, the mobility ratio has played a dominant influence in the recovery enhancement especially in the first period of pore-volume injectivity and after the formation of external filter cake both of mobility ratios have a slight increasing trend.

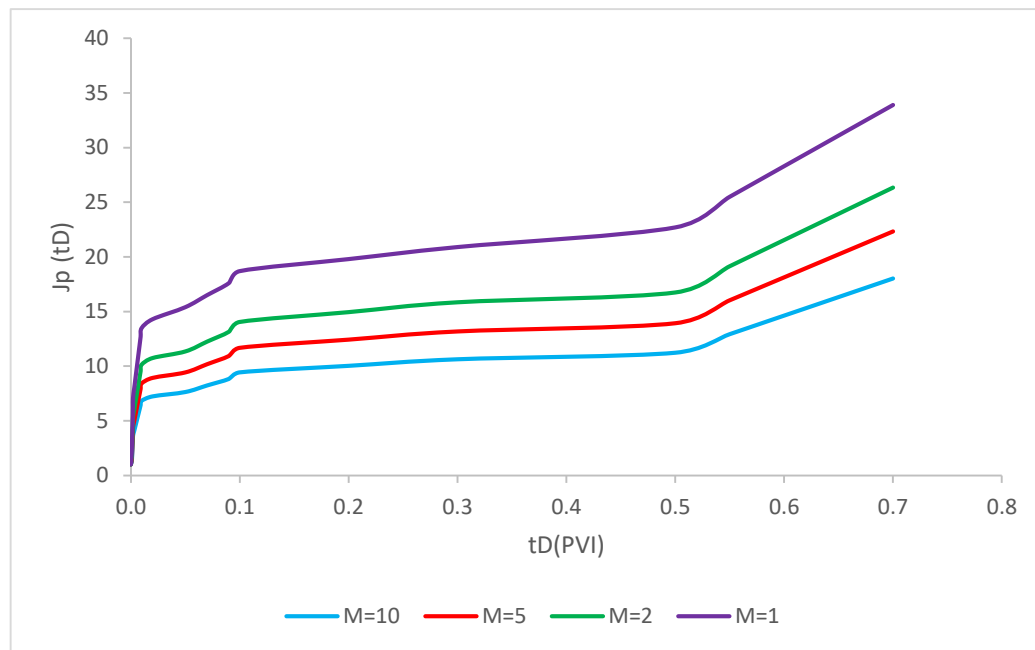


Figure 5. Axisymmetric two-phase polymer flow with simultaneous deep-bed filtration of injected particles for scenario 1 ($r_w = 0.25$ ft; $r_e = 0.1200$ ft; $\Lambda = 1$ 1/ft; $C_{max} = 2.2 \times 10^{-6}$ ppm; $b = 10$; $B_f = 4000$; $R = 1500$; $C_p = 0.002$ ppm; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$).

3.2. Formation-Damage Coefficient (β_f)

Filtration coefficients of 500, 1000, 2000 and 4000 were considered in this model. As evident in Figure 6, the injection of polymer solution with the formation-damage coefficient (β_f) of 500, 1000, 2000 and 4000 coupled with the simultaneous nanoparticle injection were analyzed. The recovery factor has risen drastically in the first period of injection due to the significant influence of polymers in the settlement of water. The reason for this sharp rise is due to the formation of filter cake in this time period. After this, it has increased slightly in the next pore-volume injectivity and this is related to the deposition of polymer junks in the pores. Moreover, as shown in Figure 6 by the higher value of formation-damage coefficient (β_f), the higher recovery factor was calculated. Consequently, the formation-damage coefficient (β_f) played a dominant influence in the recovery enhancement especially in the first period of pore-volume injectivity and after the formation of external filter cake both of mobility ratios have a slight increasing trend.

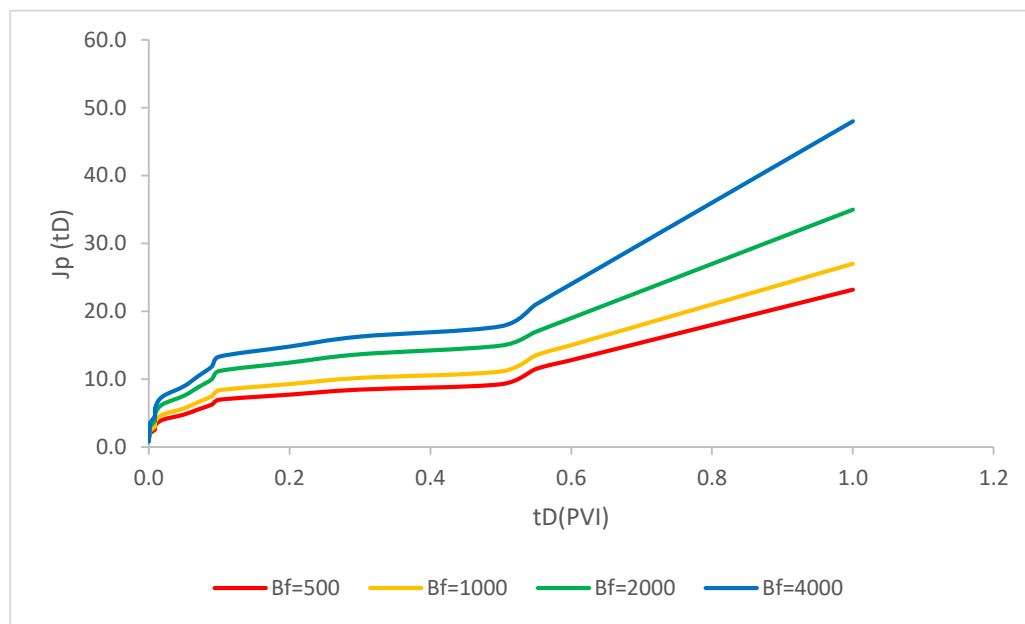


Figure 6. Axisymmetric two-phase polymer flow with simultaneous deep-bed filtration of injected particles for scenario 2 ($r_w = 0.25$ ft; $r_e = 0.1200$ ft; $\Lambda = 1$ 1/ft; $C_{max} = 2.2 \times 10^{-6}$ ppm; $b = 10$; $M = 2$; $R = 1500$; $C_p = 0.002$ ppm; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$).

3.3. Polymer Concentration

Polymer concentrations of 500, 1000, 2000, 5000 and 10,000 were considered in this model. As evident in Figure 7, the recovery factor for the injection of polymer solution with the polymer concentration of 500, 1000, 2000, 5000 and 10,000 ppm coupled with the simultaneous nanoparticle injection were calculated. The recovery factor rose drastically in the first period of injection due to the significant influence of polymers in the settlement of water. The reason for this sharp rise is due to the formation of filter cake in this time period. As the time of polymer injection in the pore volume increased, the recovery factor also rose during the first time periods before the equilibrium time that reached a constant value. Furthermore, as shown in Figure 7, a higher value of polymer concentration leads to a higher recovery factor due to increased mobilization of oil through the porous media. Consequently, a higher polymer concentration has a higher recovery factor and plays a dominant influence in the recovery enhancement—especially in the first period of pore-volume injectivity and after the formation of external filter cake—in which both mobility ratios have a slight increasing trend. This phenomenon is elaborated as the dispersion of more polymer solutions in the reservoirs and subsequently lead to mobilize more oil volume than water.

3.4. Permeability-Reduction Factor (R) Variations

As evident in Figure 8, the recovery factor for the injection of polymer solution with the permeability-reduction factor of 100, 500, 1000, 1500 and 4000 coupled with the simultaneous nanoparticle injection were modeled. The recovery factor rose drastically in the first period of injection due to the significant influence of polymers in the settlement of water. The reason for this sharp rise is due to the formation of filter cake in this time period. As the time of polymer injection in the pore volume increased, the recovery factor showed a steep rise as same as first time periods before the equilibrium time that reached a constant value. Consequently, the effect of permeability-reduction factor has not altered the recovery factor significantly.

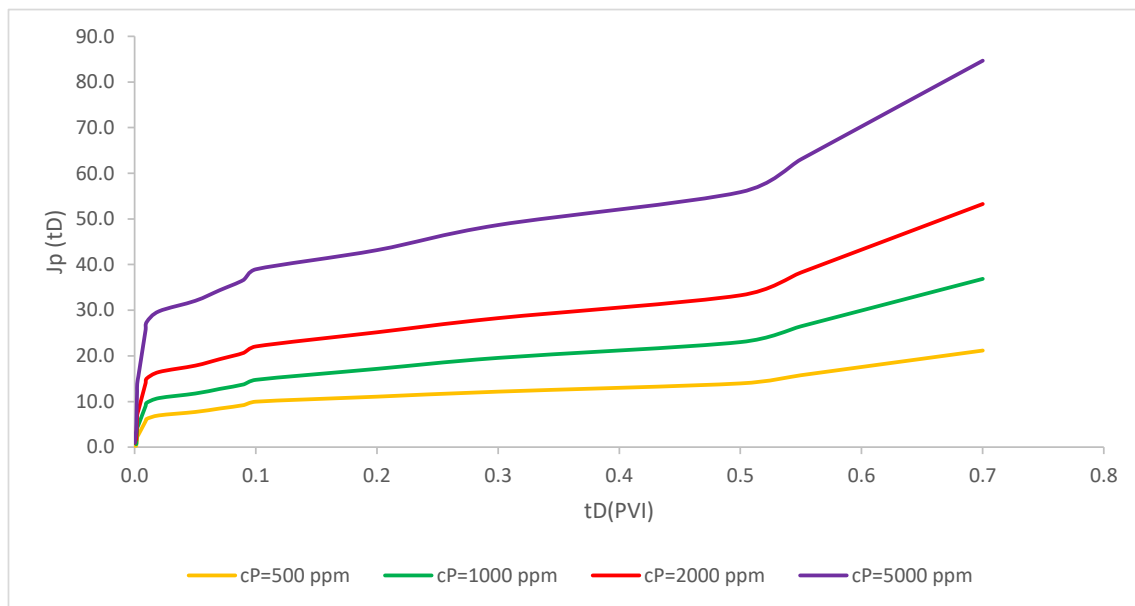


Figure 7. Axisymmetric two-phase polymer flow with simultaneous deep-bed filtration of injected particles ($r_w = 0.25$ ft; $r_e = 0.1200$ ft; $\Lambda = 1$ 1/ft; $C_{max} = 2.2 \times 10^{-6}$ ppm; $b = 10$; $M = 2$; $B_f = 4000$; $R = 1500$; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$).

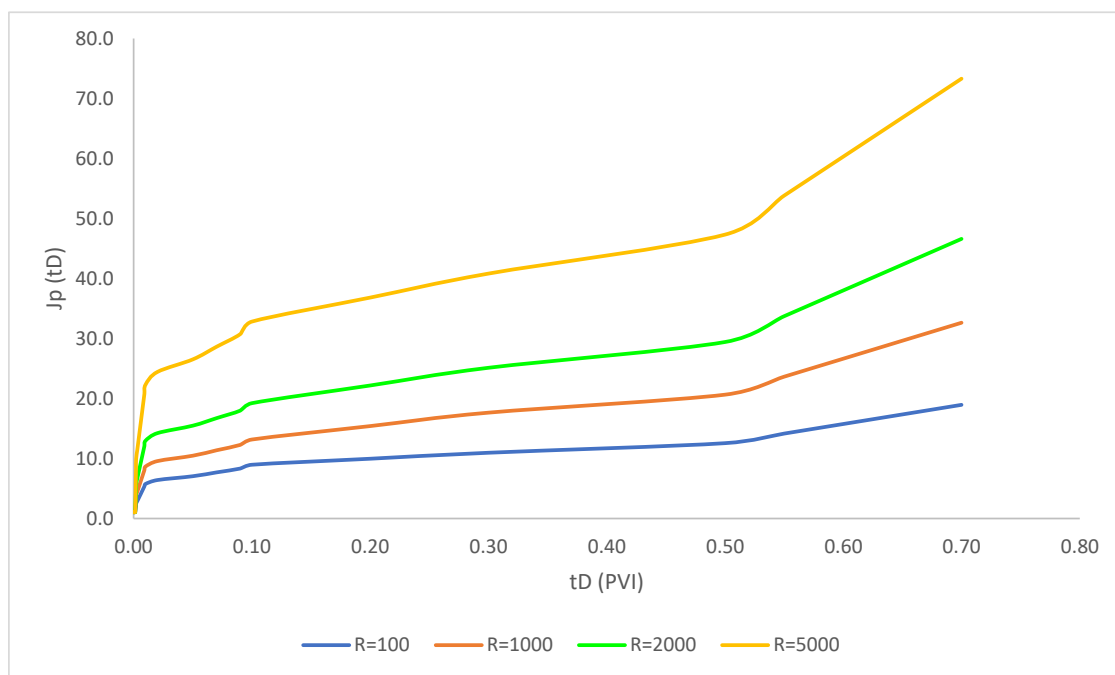
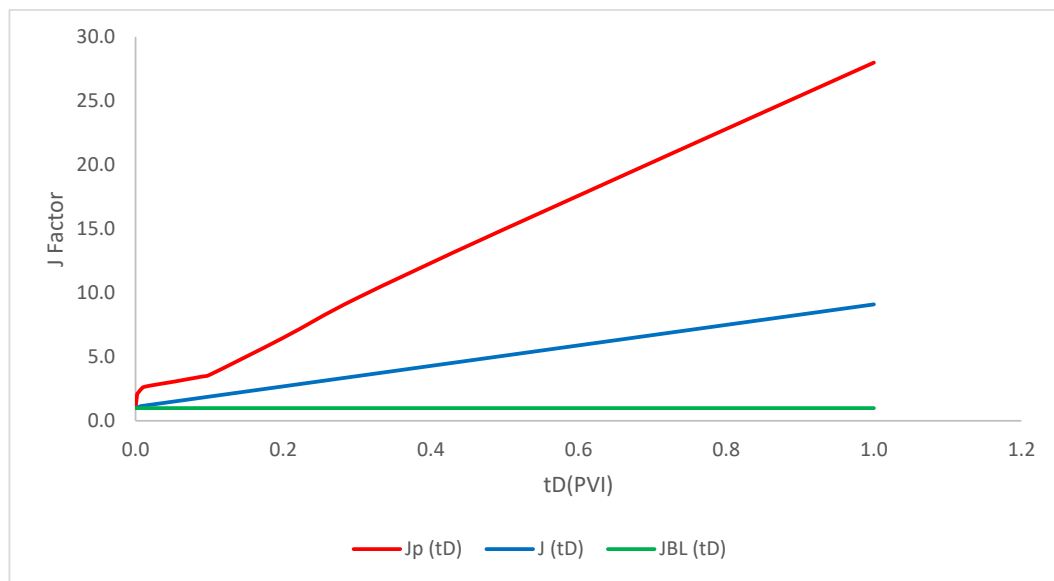


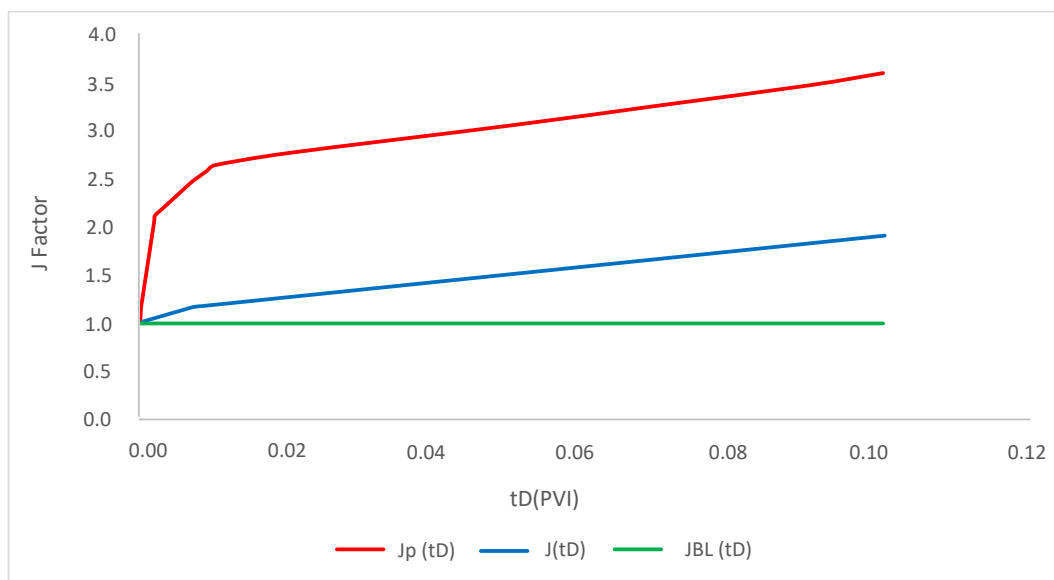
Figure 8. Axisymmetric two-phase polymer flow with simultaneous deep-bed filtration of injected particles ($r_w = 0.25$ ft; $r_e = 0.1200$ ft; $\Lambda = 1$ 1/ft; $C_{max} = 2.2 \times 10^{-6}$ ppm; $b = 10$; $M = 2$; $B_f = 4000$; $C_p = 0.002$ ppm; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$).

3.5. The Comparison of Each Injectivity Mode

The comparison of each injectivity mode is schematically plotted in Figures 9 and 10 for the both mobility ratio of 1 and 10.

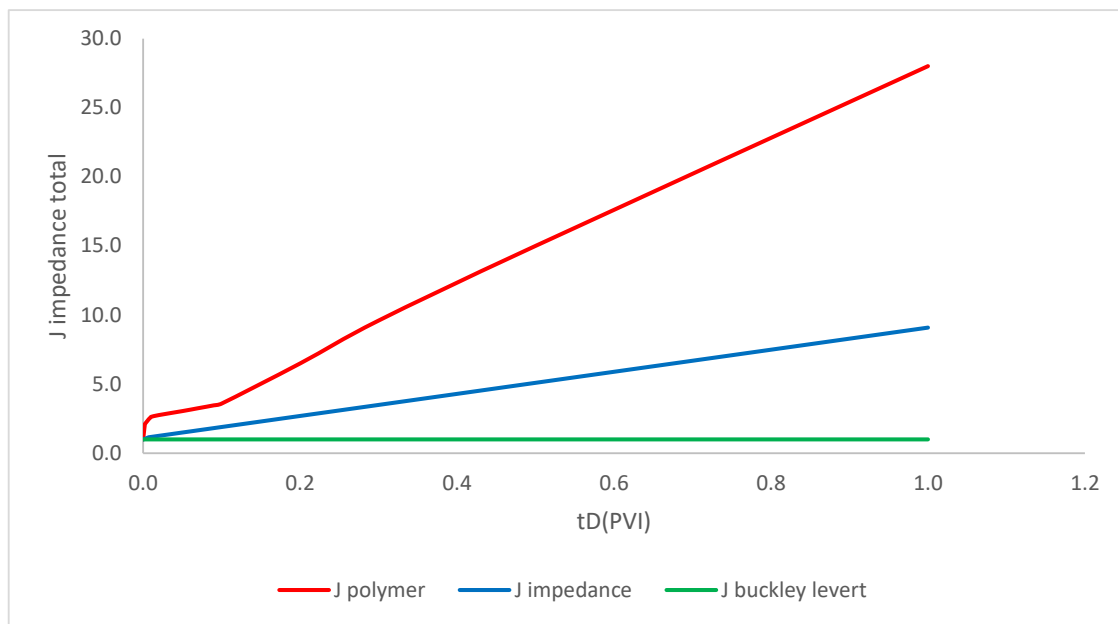


(a)

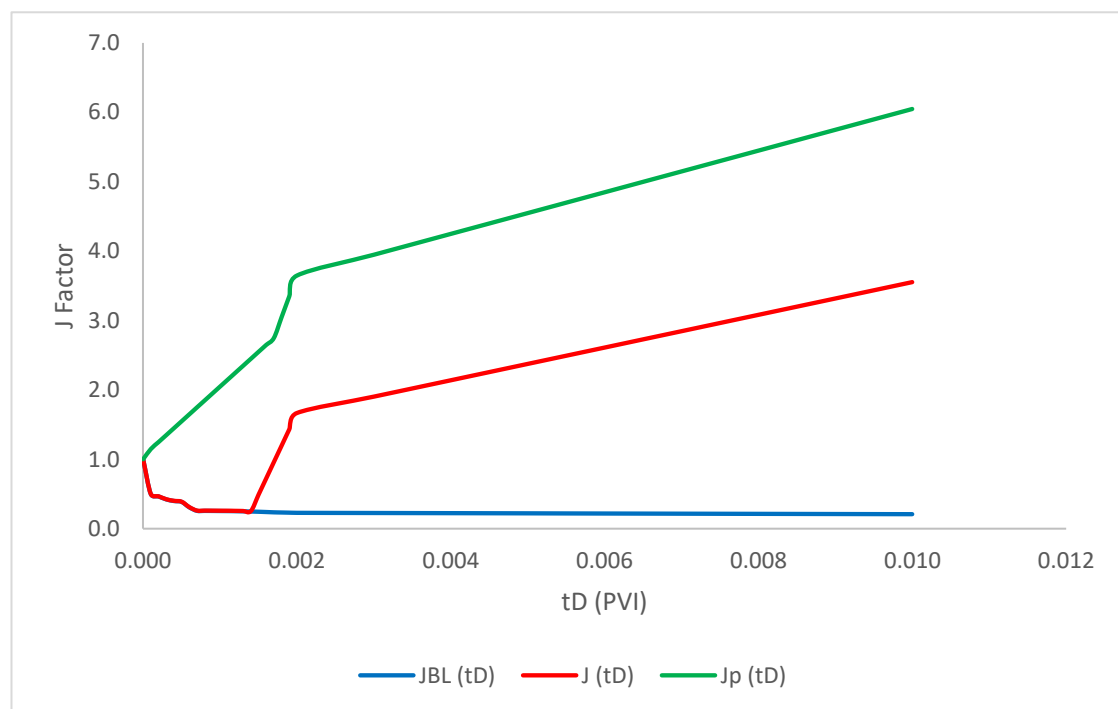


(b)

Figure 9. Comparison of each injectivity mode for $M = 1$ (detailed). (a) Pore volume injection period; (b) detailed plot. $M = 1$; $r_w = 0.25 \text{ ft}$; $r_e = 0.1200 \text{ ft}$; $\Lambda = 1 \text{ 1/ft}$; $C_{max} = 2.2 \times 10^{-6} \text{ ppm}$; $b = 10$; $B_f = 4000$; $R = 1500$; $C_p = 0.002 \text{ ppm}$; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$.



(a)



(b)

Figure 10. Comparison of each injectivity mode for $M = 10$ (detailed). (a) Pore volume injection period; (b) detailed plot. $M = 10$; $r_w = 0.25$ ft; $r_e = 0.1200$ ft; $\Lambda = 1$ 1/ft; $C_{max} = 2.2 \times 10^{-6}$ ppm; $b = 10$; $B_f = 4000$; $R = 1500$; $C_p = 0.002$ ppm; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$.

3.6. Validity of the Proposed Model with the Field Data

To validate the proposed model with the field data, the Berea sandstone core which was used in Fletcher et al. (1992). As shown in Figures 11 and 12, three sets of models were proposed to match with the field data. Thereby, according to the results of proposed model, for the Core sample 1, the selected model with the mobility ratio of 2 are in a good agreement with the experimental investigation. For

the Core sample 2, the selected model with the mobility ratio of 5 are in a good agreement which demonstrated the appropriateness of the proposed model (Fletcher et al. 1992).

Polymer flooding is considered as one of the most technical and economic improved oil-recovery procedures to develop sweep efficiency by reducing water viscosity, which, in turn, leads to producing more oil volume in the wellbore. In this way, an appropriate estimation of the properties of injected polymer solutions with the reservoir properties would be the essential first step before flooding processes and considered as the major challenges of polymer application in hydrocarbon reservoirs. A proposed analytical model (Equation (3)) was developed for injectivity scenarios in the homogeneous reservoir. To investigate the profound impact of each phenomenon on the pressure drop and subsequently on the impedance, we concentrated on each parameter in detail to compare them properly.

To find the considerable influence of mobility ratio, polymer concentration and formation-damage coefficient variations on the pressure drop, it is evident that mobility enhancement has provided higher pressure drop, due to the more possible spaces for oil movement, which directly leads to a higher pressure drop value. In addition, the propagation of polymers into the porous media is strongly controlled by the physical adsorption of polymer molecules and the polymer entrapment in the provided solvent. The polymer retention rate utterly depends on the flow rate, size of the pore-throats, concentration of injected polymers and the molecular form of the polymers. Thereby, a higher polymer concentration would lead to a greater pressure drop and increasing sweep efficiency. However, as shown, according to the analytical solutions for the dominant influence of formation-damage coefficient on the pressure drop, it has a similar increase pattern-like mobility ratio and polymer concentration alteration. An increasing trend for this parameter leads to a gradual increase which would then reach a plateau after the stabilization of particle distribution near the wellbore. Otherwise, this extensive model could be utilized in the viscous dominated waterflooding operations which has occurred in reservoirs with layer-cake.

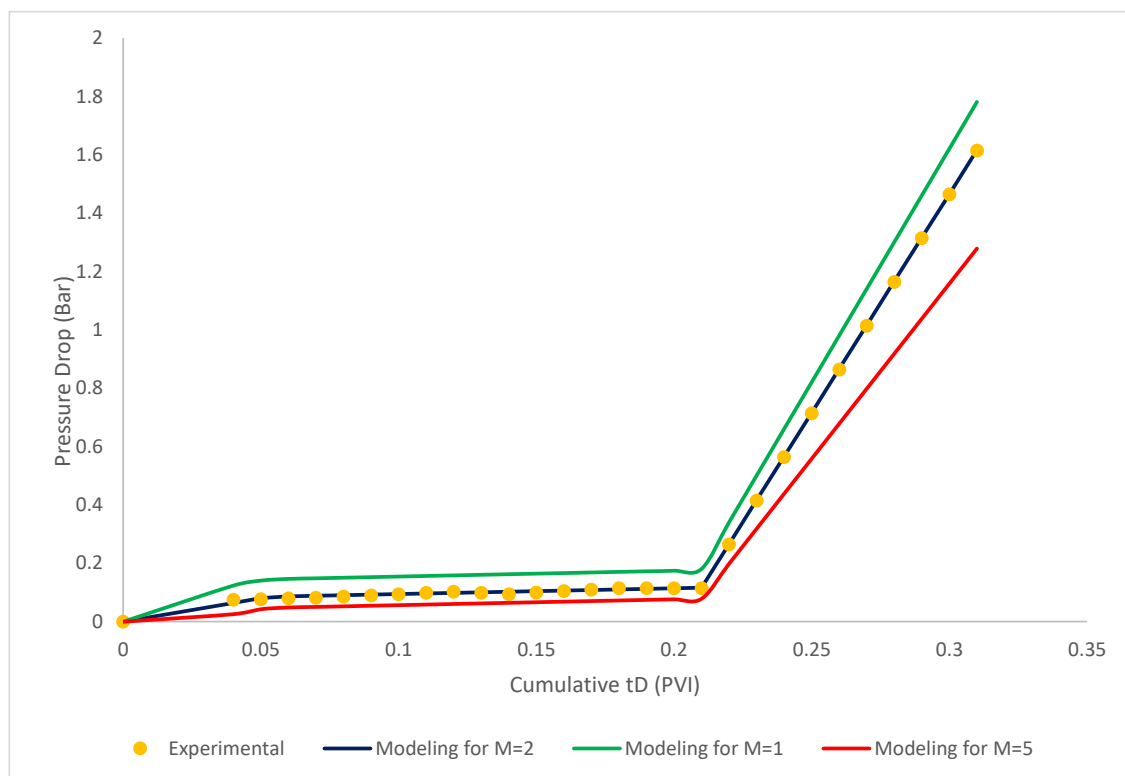


Figure 11. Comparison of Core sample 1 and the proposed model. Blue line— $M = 2$, green line— $M = 1$, red line for $M = 5$; $\Lambda = 20$; $C_{max} = 1000 \times 10^{-6}$; $b = 10$; $B_f = 10$; $R = 1000$; $C_p = 500 \times 10^{-6}$; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$.

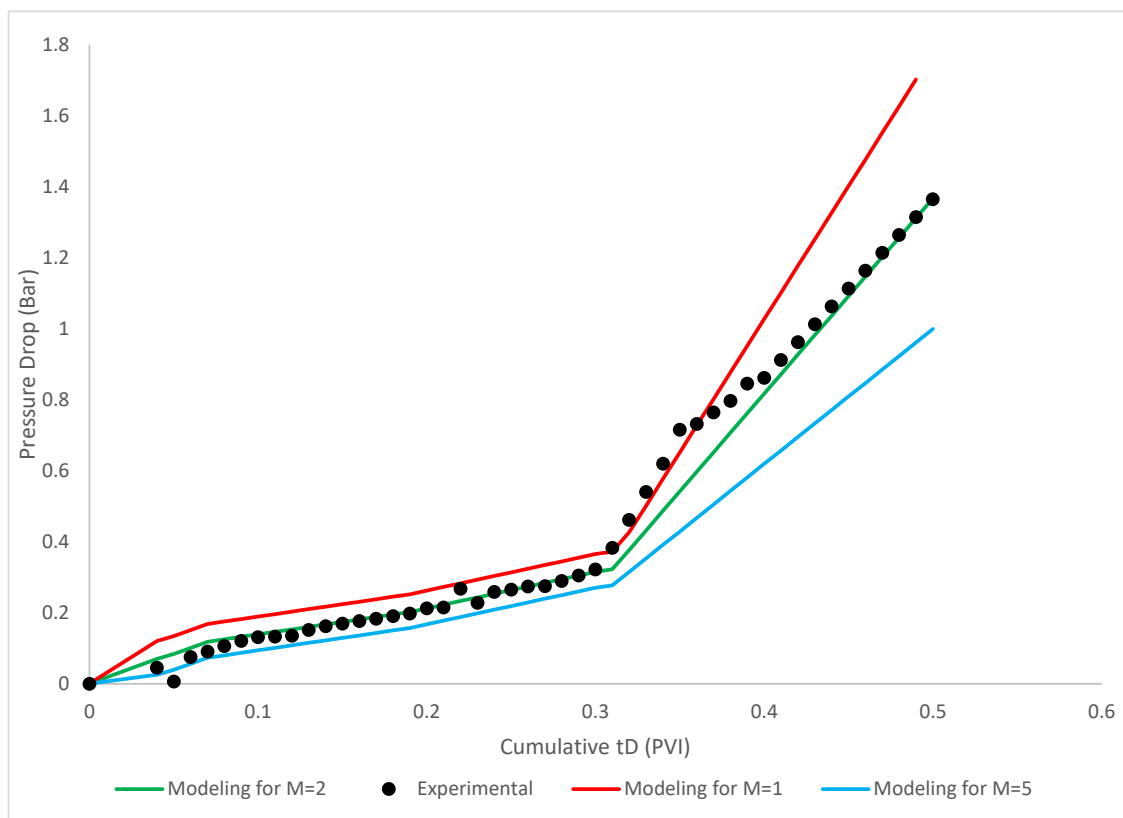


Figure 12. Comparison of Core sample 2 and the proposed model. Blue line— $M = 5$, green line— $M = 2$, red line— $M = 1$; $\Lambda = 1$; $C_{max} = 1000 \times 10^{-6}$; $b = 10$; $B_f = 100$; $R = 1000$; $C_p = 1500 \times 10^{-6}$; $\Phi = 0.28$; $\Phi_c = 0.15$; $\beta = 100$; $c^o = 5 \times 10^{-6}$.

Neglecting the combination of the effects of three-phase displacement while deriving the mathematical model may lead to an inappropriate interpretation of well-injectivity history. To ensure the significant impact of the rheological properties of the reservoir and polymer, the characteristics of the total impedance, coupled with simultaneous effects of formation damage are taken into consideration. By the considering the constant assumptions for the comparison of each parameter, it is demonstrated that higher mobility ratio, polymer concentration and formation-damage coefficient values would be directly related to higher values of total impedance for polymer injectivity with the coupling of formation-damage effects. The permeability-reduction factor has not altered the recovery factor, thus it would be negligible in the calculations.

4. Conclusions

Polymer flooding is an EOR technique that is particularly relevant to heavy oil reservoirs. In the coming decades, petroleum industries will concentrate more on the improvement of this technique, how to virtually eliminate its inefficiencies to obtain the best results and subsequently, how to obtain the most recoverable oil from reservoirs. The injection of polymer solutions could be strictly emphasized by the rheology of polymers, pore-throat plugs caused by polymer junk, polymer adsorption and the high-viscosity of the polymer in the solution used. According to the conceptual nurture of formation rheological parameters and polymer concentration, the main results of this study are as follows:

The principal parameters that play a substantial role in the pressure drop and recovery of the polymer flooding technique are the mobility ratio (M), formation-damage coefficient (βf) and polymer concentration. In other words, the other parameters such as the resistance, or permeability-reduction factor (R), porosity (Φ), filtration coefficient (Λ), concentration of the polymer solution, maximum dimensionless adsorbed-polymer concentration (C_{max}) and nonlinearity of

the isotherm (b) would not be an effective on the calculation of pressure drop and recovery factor. Thereby, the effect of these parameters can be considered negligible.

Analytical-type curves show that higher values of mobility ratio, formation-damage coefficient and polymer concentration lead to a steep rise in both pressure drop and recovery curves versus the time of pore volume injection. In this way, after the external cake was performed with the maximum thickness, the pressure drop reached a constant value at the equilibrium time and hence, the recovery factor has stabilized in this period.

In this extensive study, we coupled filtration theory with the simultaneous injection of a polymer solution to compare the results of each step and distinguish the differences of each method. In addition, the dominant influence of formation rheological parameters and polymer concentration were added to the mathematical model to investigate the importance of them.

Funding: This research received no external funding.

Conflicts of Interest: The authors declare no conflict of interest.

Nomenclature

b	Langmuir polymer adsorption parameter (dimensionless)
C_{max}	Maximum dimensionless adsorbed-polymer concentration
C_o	Injection concentration (m^3 polymer/ m^3 aqueous phase)
C_p	Polymer concentration in aqueous phase (m^3 polymer/ m^3 aqueous phase)
Π	Injectivity index ($m^4 s kg^{-1}$)
$J(t)$	Impedance (dimensionless)
J_{BL}	Damage-free impedance (dimensionless)
$J_{polymer}$	Polymer impedance (dimensionless)
M	Mobility ratio (dimensionless)
m	Slope of impedance growth during deep-bed filtration (dimensionless)
m_c	Slope of impedance growth during cake formation (dimensionless)
K	Permeability (m^2)
k_{rowi}	Oil-phase relative permeability at initial water saturation (dimensionless)
p	Pressure (Nm^{-2})
p_w	Wellbore pressure (Nm^{-2})
p_{res}	Reservoir pressure (Nm^{-2})
R	Permeability-reduction (or resistance) factor due to polymer adsorption (dimensionless)
r_w	Wellbore radius (m)
r_e	Reservoir radius (m)
q	Injection rate ($m^3 s^{-1}$)
S	Dimensionless trapped (retained) polymer concentration
t_D	Dimensionless time
t_e	Dimensionless stabilization time (PVI)
t_{tr}	Dimensionless transition time (PVI)
t_{BT}	Breakthrough time (PVI)
x_D	Dimensionless distance
x_{Df}	Dimensionless front position
x_w	Dimensionless squared radius
Λ	Dimensionless filtration coefficient
β	Formation-damage coefficient (dimensionless)
ϕ	Porosity (fraction)
PVI	Pore volume injection

Appendix A

Pressure drop calculation for polymer injectivity case:

- The pressure drop before breakthrough time can be calculated from Equation (A1) [12,17]:

$$\begin{aligned} \Delta P = x_{Df} + & \frac{M}{\Lambda} (1 - e^{-\Lambda x_{Df}}) \\ & + R\phi c_o \left[\frac{M\hat{C}_{max}}{\Lambda} (1 - e^{-\Lambda x_{Df}}) + \frac{\hat{C}_{max}}{\Lambda} \left(\frac{M}{b} - 1 \right) \ln \left(\frac{1 + be^{-\Lambda x_{Df}}}{1 + b} \right) \right] \\ & + \beta \phi c_o \left[\frac{\hat{C}_{max}}{\Lambda} \left(1 + be^{-\Lambda x_{Df}} + \frac{M}{2} (be^{-2\Lambda x_{Df}} - \frac{1}{b}) \right) \ln \left(\frac{1 + be^{-\Lambda x_{Df}}}{1 + b} \right) \right. \\ & + x_{Df} \left(1 + b\hat{C}_{max} \right) \left(1 + \frac{M}{2} e^{-\Lambda x_{Df}} \right) e^{-\Lambda x_{Df}} \\ & \left. + (1 - e^{-\Lambda x_{Df}}) \left(t_D - \frac{1}{\Lambda} \left(1 + \frac{M\hat{C}_{max}}{2} \right) \right) + \frac{M}{2} (1 - e^{-\Lambda x_{Df}}) \left(t_D - \frac{1}{2\Lambda} \right) \right] \end{aligned} \quad (A1)$$

where Λ is the dimensionless filtration coefficient, x_{Df} is the dimensionless front position, R is the permeability-reduction (or resistance) factor due to polymer adsorption, c_o is the injection concentration, \hat{C}_{max} is the maximum dimensionless adsorbed-polymer concentration, b is the Langmuir polymer adsorption parameter, and β is the formation-damage coefficient.

- After polymer breakthrough, the integration in x_D is performed from zero to one, and the pressure is calculated by inserting $x_{Df} = 1$ in Equation (A1):

$$\begin{aligned} \Delta P = 1 + & \left(\frac{M}{\Lambda} + \beta \phi c_o t_D - \frac{\beta \phi c_o}{\Lambda} \left(1 + \frac{M\hat{C}_{max}}{2} \right) + R\phi c_o \frac{M\hat{C}_{max}}{\Lambda} \right) (1 - e^{-\Lambda}) \\ & \left[R\phi c_o \frac{\hat{C}_{max}}{\Lambda} \left(\frac{M}{b} - 1 \right) + \beta \phi c_o \frac{\hat{C}_{max}}{\Lambda} \left(1 + be^{-\Lambda} + \frac{M}{2} (be^{-2\Lambda} - \frac{1}{b}) \right) \ln \left(\frac{1 + be^{-\Lambda}}{1 + b} \right) \right] \\ & + \beta \phi c_o \left[\left(1 + b\hat{C}_{max} \right) \left(1 + \frac{M}{2} e^{-\Lambda} \right) e^{-\Lambda} + \frac{M}{2} (1 - e^{-2\Lambda}) \left(t_D - \frac{1}{2\Lambda} \right) \right] \end{aligned} \quad (A2)$$

Thereby, the total pressure drop is calculated by:

$$\Delta p_{total} = \Delta p_{Before\ breakthrough} + \Delta p_{after\ breakthrough} \quad (A3)$$

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